Comments on the Proposed Regulation Integrity Management Program for Gas Distribution Pipelines

Docket No. PHMSA-RSPA-2004-19854

Decatur Utilities is a publicly-owned natural gas utility serving approximately 15,000 customers in the state of Alabama. As a natural gas utility we must comply with the pipeline safety regulations issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA), therefore we are very interested in the proposed Distribution Integrity Management Program (DIMP) rule.

We are committed to operate and maintain our natural gas distribution system to protect public safety. Writing plans, submitting reports to the government and other administrative requirements of federal regulations take time and money that could be used to inspect and maintain the natural gas system, and provide more economical gas service for our customers. In writing the final rule, we urge PHMSA to minimize the amount of paperwork this rule will require. We support the comments of the American Public Gas Association (APGA).

We would like to comment about the proposed regulations. Here are some specific comments concerning several areas of the proposed rule:

Proposed Code Section (subject-excess flow valves):

Sec. 192.1011 When must an Excess Flow Valve (EFV) be installed?

(a) General requirements. This section only applies to new or replaced service lines serving single-family residences. An EFV installation must comply with the requirements in Sec. 192.381.

(b) Installation required. The operator must install an EFV on the service line installed or entirely replaced after [INSERT DATE 90 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE Federal Register], unless one or more of the following conditions is present:

(1) The service line does not operate at a pressure of 10 psig or greater throughout the year;

(2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence;

(3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

(4) An EFV meeting performance requirements in Sec. 192.381 is not commercially available to the operator.

Decatur Utilities' comment:

We recognize that this is a requirement from the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act). We just feel that since this is a service line design

requirement, we recommend that it be placed along with the other service line design requirements in Subpart H replacing the current EFV notification language in Section 192.383.

Proposed Code Section (subject-required IM program elements):

Sec. 192.1007 What are the required integrity management (IM) program elements?

(a) Knowledge. An operator must demonstrate an understanding of the gas distribution system.

(1) Identify the characteristics of the system and the environmental factors that are necessary to assess the applicable threats and risks to the gas distribution system.

Decatur Utilities' comment:

The meaning of "environmental factors" is not clear. It should be clarified to possibly mean such things as areas where washouts, landslides, or sink holes are known to occur, or geographical areas where hurricanes or tornados are more likely to occur, not areas where environmental impacts would be worse. Gas pipeline releases do not release oil or other liquids which have the potential to cause environmental damage.

Proposed Code Section (subject-identification of threats):

....(b) Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment malfunction, inappropriate operation, and any other concerns that could threaten the integrity of the pipeline. An operator must gather data from the following sources to identify existing and potential threats: incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and "one call" and excavation damage experience. In considering the threat of inappropriate operation, the operator must evaluate the contribution of human error to risk and the potential role of people in preventing and mitigating the impact of events contributing to risk. This evaluation must also consider the contribution of existing DOT requirements applicable to the operator's system (e.g., Operator Qualification, Drug and Alcohol Testing) in mitigating risk.

Decatur Utilities' comment:

It is not clear what "one-call experience" means or what useful information an operator would get from its one-call system that does not already exist in the operator's excavation damage experience. We recommend that "one-call experience" be deleted from this section.

In addition, "inappropriate operation" has been shown by both the AGF and Allegro studies to be a relatively minor contributor to distribution incidents. PHMSA's Distribution Annual Report data show inappropriate operation accounted for less than 3% of leaks repaired in 2007. PHMSA should not presume that all operators need to focus additional resources in this area. AS PHMSA points out, there are already requirements for drug and alcohol testing and operator qualification. If an operator's risk analysis finds that inappropriate operation is not a significant risk, no additional action should be required.

Proposed Code Section:

(d) Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline system. These measures must include implementing an effective leak management program and enhancing the operator's damage prevention program required under Sec. 192.614 of this part. To address risks posed by inappropriate operation, an operator's written IM program must contain a separate section with a heading 'Assuring Individual Performance'. In that section, an operator must list risk management measures to evaluate and manage the contribution of human error and intervention to risk (e.g., changes to the role or expertise of people), and implement measures appropriate to address the risk. In addition, this section of the written IM program must consider existing programs the operator has implemented to comply with Sec. 192.614 (damage prevention programs); Sec. 192.616 (public awareness); Subpart N of this Part (qualification of pipeline personnel), and 49 CFR Part 199 (drug and alcohol testing).

Decatur Utilities' comment:

"Inappropriate operation" has been shown by both the AGF and Allegro studies to be a relatively minor contributor to distribution incidents. PHMSA's Distribution Annual Report data show inappropriate operation accounted for less than 3% of leaks repaired in 2007. PHMSA should not presume that all operators need to focus additional resources in this area. AS PHMSA points out, there are already requirements for drug and alcohol testing and operator qualification. If an operator's risk analysis finds that inappropriate operation is not a significant risk, no additional action should be required.

We agree that gas system operators must have an effective leak management program that may allow leaks that are not hazardous to be monitored rather than immediately repaired. Operators that monitor leaks would have to apply some criteria to determine what leaks can be safely monitored. We choose to repair all leaks as they are found. We should not be required to develop criteria for determining if a leak is suitable for monitoring if we intend to repair any leak we find.

We also question the need to "enhance" our damage prevention program. If an operator's threat assessment shows that the operator's current damage prevention program is effective, no enhancements should be required. We also feel that the term "enhanced" is open to varying interpretations and not appropriate for this rule.

We feel that the best "enhancement" for gas operator damage prevention programs is to limit third-party excavation damages. Statistics we have seen show that nationwide reported leaks are overwhelmingly caused by third-party excavation damage. In calendar year 2007, 92.5% of our leaks were caused by excavation damage. We feel the laws on the books are not strong enough to discourage those excavators who damage our pipelines. We are limited to recovering only those costs that cover the costs of the materials and labor to repair the damages. Our local district attorneys are hesitant to prosecute pipeline damagers because any monies recovered are paid to the state general fund and not to the local districts where the damages occurred. We would request that PHMSA urge law makers to look at addressing the

punishment of damagers on a local level, and to make punishment more severe so as to discourage the damage to our gas distribution facilities.

Proposed Code Section:

(e) Measure performance, monitor results, and evaluate effectiveness.

(1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(i) Number of hazardous leaks either eliminated or repaired, per Sec. 192.703(c), categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(iv) Number of EFVs installed;

(v) Total number of leaks either eliminated or repaired, categorized by cause;

(vi) Number of hazardous leaks either eliminated or repaired per Sec. 192.703(c), categorized by material; and

(vii) Any additional measures to evaluate the effectiveness of the operator's program in controlling each identified threat.

Decatur Utilities' comment:

PHMSA does not define "hazardous leaks." We suggest PHMSA use the definition of a Grade 1 leak from the Gas Piping Technology Committee (GPTC) guide – "a leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous."

Number of EFVs installed is not a valid measure of the performance of an operator's integrity management program. The number of EFVs installed will depend on the number of service lines installed or replaced each year. Any trends in the number of EFVs installed will be more a measure of the effectiveness of an operator's marketing efforts than its integrity management program, or a reflection of the state of the economic health of the local community. We do not object to PHMSA requesting data on the number of EFVs installed, but we object to the requirement that an operator must consider the number of EFVs installed when evaluating the effectiveness of its IM program.

PHMSA is proposing to require us to keep track of every time an excavator damages one of our pipelines. Currently we keep track of damages when we have to fix a leak and we file this with our annual pipeline safety report. We support keeping the excavation damage reporting the way it is.

PHMSA is proposing to collect data on the number of excavation damages and excavation tickets in order to track trends in the number of damages per ticket. We agree that data on the number of locate requests is a valid indicator of the level of excavation activity and will allow users of the data to normalize damage count for the level of excavation activity. We believe that, rather than reporting the number of excavation damages, PHMSA should maintain its current requirement that operators report the number of excavation leaks repaired. Excavation damage that causes a leak is a clear cut definition – damage, as PHMSA proposes to define it, is not clear cut. Even though there would be more data if PHMSA required all damages to be reported, leak repair data can serve PHMSA's purpose just as well.

Proposed Code Section:

(f) Periodic Evaluation and Improvement. An operator must continually re-evaluate threats and risks on its entire system and consider the relevance of threats in one location to other areas. In addition, each operator must periodically evaluate the effectiveness of its program for assuring individual performance to reassess the contribution of human error to risk and to identify opportunities to intervene to reduce further the human contribution to risk (e.g., improve targeting of damage prevention efforts). Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations. [emphasis added]

Decatur Utilities' comment:

The word "continually" suggests something must be done constantly, 24 hours a day, 7 days a week. That is clearly not feasible. We think "periodically" would better express PHMSA's intent.

Once again, the focus on assuring individual performance is not appropriate. This should only be required if the threat analysis identifies inappropriate operations as a threat requiring additional action. We already have an operator qualification program, a drug and alcohol testing program and a damage prevention program. We have not had any accidents caused by our employees so we don't see any benefit in including in our integrity management plan a section on "Assuring Individual Performance." That would just be more unnecessary paperwork. The existing rules are adequate to ensure our workers are qualified.

Proposed Code Section:

Sec. 192.1015 What records must an operator keep?

Except for the performance measures records required in Sec. 192.1007, an operator must maintain, for the useful life of the pipeline, records demonstrating compliance with the requirements of this subpart. At a minimum, an operator must maintain the following records for review during an inspection:

(a) A written IM program in accordance with Sec.192.1005;

(b) Documents supporting threat identification;

(c) A written procedure for ranking the threats;

(d) Documents to support any decision, analysis, or process developed and used to implement and evaluate each element of the IM program;

(e) Records identifying changes made to the IM program, or its elements, including a description of the change and the reason it was made; and

(f) Records on performance measures. However, an operator must only retain records of performance measures for ten years.

Decatur Utilities' comment:

The rule would require us to forever keep records of

- Documents supporting threat identification;
- Written procedures for ranking the threats;
- Documents to support any decision, analysis, or process developed and used to implement and evaluate each element of the IM program;
- Records identifying changes made to the IM program, or its elements, including a description of the change and the reason it was made;
  and, for 10 years,
- Records on performance measures

These aren't records that would be of any value to us in operating and maintaining our system. There are already requirements to keep all our inspection and maintenance records. We think PHMSA should keep the current recordkeeping periods for our inspection and maintenance records and not require us to document all the details of how we develop our IM plan..

We feel this recordkeeping is unduly burdensome. In effect, PHMSA is extending the recordkeeping for every inspection record used during the development of the IM plan to the lifetime of the pipe. We believe the inspection record retention requirements in the current regulations should be left unchanged.

PHMSA is also requiring an operator to maintain a record of every change made to the IM program and maintain these records for as long as the system remains in existence. A more reasonable requirement would be to maintain such records through the next audit cycle. It is reasonable to allow auditors the opportunity to question changes made since the last audit – it is not reasonable to question changes made fifty or one hundred years ago, yet under the PHMSA proposal operators would be expected to have today's records one hundred years from now.

Proposed Code Section (plastic pipe failure):

Sec. 192.1009 What must an operator report when plastic pipe fails?

Each operator must report information relating to each material failure of plastic pipe (including fittings, couplings, valves and joints) no later than 90 days after failure. This information must include, at a minimum, location of the failure in the system, nominal pipe size, material type, nature of failure including any contribution of local pipeline environment, pipe manufacturer, lot number and date of manufacture, and other information that can be found in markings on the failed pipe. An operator must send the information report as indicated in Sec. 192.1013. An operator must also report this information to the State pipeline safety authority in the State where the gas distribution pipeline is located.

Decatur Utilities' comment:

A joint industry/government project to voluntarily collect and analyze plastic pipe failure data (Plastic Pipe Database Committee (PPDC)) has been ongoing for several years. We have participated in this program since its inception. PHMSA has issued several advisory bulletins based on PPDC analyses. APGA and AGA, the American Gas Association, distribute the advisory to their members. APGA has published articles in its Public Gas News about the advisories as well as faxing out the notice to members. In fact, PPDC information is widely available to operators.

APGA has reported, "In the online Frequently Asked Questions about this rule PHMSA states that it is small operators who are desirous of obtaining access to the raw data in order to perform their own statistical analysis. Nothing could be further from the truth. Small operators prefer the current system in which failure data submittal is voluntary and a group of industry and government experts analyze the data and summarize the results. Small operators generally do not provide failure data because data submittal is burdensome. Although only about 10% of operators currently submit data to the PPDC, these systems own more than 70% of plastic pipe mileage, more than sufficient for valid statistical analysis. Forcing the remaining 90% of systems to submit failure data would impose significant burdens of these systems without any benefit and possibly detriment if the data submitted by small systems is not accurate."

We believe the PPDC has been a success and by switching to a mandatory, government run program PHMSA risks denying the industry the benefits of this valuable effort. We would support improvements within the PPDC framework to address PHMSA's concerns.

PHMSA is proposing to require detailed reports about the cause of all failures on plastic pipe and components. We urge PHMSA to keep this program voluntary so that other gas operators who choose not to participate are not forced to devote more resources to filling out these reports. We want to continue to be told if safety problems are found with any products being used by other gas operators but do not want to see the individual reports that other utilities are voluntarily submitting. We don't have the time to wade through all that data.

We appreciate the opportunity to comment on this proposed rule.

Respectfully Submitted,

DECATUR UTILITIES

Jerry B. Parker, Senior Engineer

(256) 552-1404

Date: October 23, 2008